

Chapter 5

NATURAL GAS MARKET TRENDS

INTRODUCTION

Natural gas will remain a major California energy source for decades to come. Gas supplies should be adequate and pipeline capacity to deliver the gas will exceed requirements for at least the next 20 years. Gas prices should remain affordable throughout the period. Since the price that producers charge for gas is now deregulated, the sale of gas has become highly competitive. Gas transmission is also becoming increasingly competitive. Thus, both state and federal regulatory agencies have instituted market-sensitive regulations designed to promote gas market competition and keep prices low, while maintaining service reliability.

This chapter discusses current natural gas market conditions in California and the rest of North America, followed by a discussion on how regulatory reforms have progressed since the *1993 Fuels Report*. The chapter then focuses on the outlook for demand, supply, and price of natural gas for the forecasted 20-year horizon. It also addresses uncertainties associated with natural gas supply and price projections based on a scenario analysis approach with sensitivity analyses of specific key factors that influence the future of natural gas price and supply availability. The next section discusses the conceptual issues relating to integrated resource planning and demand side management and focuses on the current status of the two programs. The concluding portion of the chapter addresses the forecast of coal prices to specific coal-fired power plants in the northwest and southwest regions of the United States.

CURRENT GAS MARKET CONDITIONS

Natural gas market conditions look much as they did at the time of the *1993 Fuels Report*. Abundant gas supplies are available from a diversity of geographical areas. Gas consumption has continued to rise slowly in California and the nation, while prices have remained low. Progress continues to be made in moving the gas industry toward increased responsiveness to market forces rather than regulatory control.

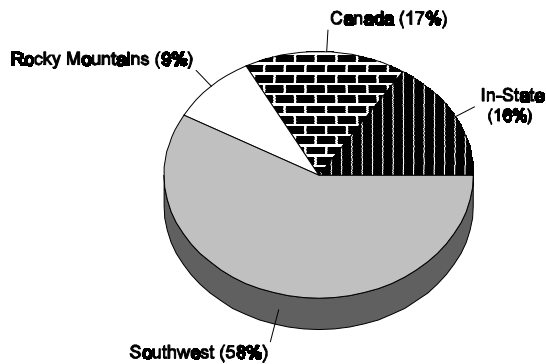
Gas Supply

Natural gas continues to be abundant. Estimates of the size of the North American gas resource have increased substantially over the past few years, as technological improvements in exploration and drilling activity allow producers to access resources previously not considered recoverable.

An integrated, continent-wide gas market exists in North America, connected by a complex grid of long-distance interstate and international pipelines. The directions and magnitudes of gas flows in the pipeline system are sensitive to gas prices and other market forces. Major gas market events in any region affect all other regions through a ripple effect.

California gets its natural gas from a variety of geographical areas (see Figure 5-1). In 1992, 16

Figure 5-1
1992 California Natural Gas Supplies by Source



percent was produced within the state. Another 17 percent came from Canada and 9 percent from the Rocky Mountains area. The remaining 58 percent came from southwestern states, principally New Mexico and West Texas.

Unlike the gas pipeline capacity shortages of the 1980s, California now has an excess of pipeline capacity connecting the state to its major gas supply regions. That capacity has increased from 4.6 billion cubic feet per day (BCF/D) during the late 1980s to approximately 6.8 BCF/D today. New pipeline capacity and expansion of existing capacity has enhanced California's ability to receive gas from all its major gas supply regions. That excess promotes competition among gas supply regions to sell gas to California, as well as competition among pipeline companies to deliver the gas. The competition helps keep gas prices low.

As gas regulatory reform has progressed over the last decade, the gas market has been witnessing the "commoditization" of gas. With each passing year gas is behaving more like traditionally unregulated commodities. The market continues to mature, competition intensifies, and barriers to market entry decrease. Large numbers of unregulated gas marketers and other entrepreneurs have emerged, focusing on providing new services and adding value wherever it will generate a profit. There is an active market in futures, options, swaps, and other financial tools to help producers and consumers manage risks. Several companies now offer computer-based, real-time, electronic data interchange systems for disseminating information and conducting gas sales.

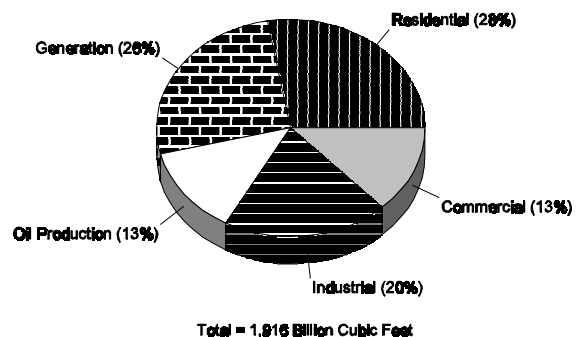
Perhaps the most significant recent development in gas markets is the rapid emergence of market centers. A market center is an area where several pipelines interconnect, with a central operator facilitating the interchange of gas. It is a location for one-stop shopping, bringing many buyers and sellers together to enhance competition and provide greater service reliability. In addition to facilitating sales transactions, a market center can provide a variety of services, including gas storage, balancing, accounting, and electronic information services. The price discovery and ease of transactions afforded by market centers can lead to lower gas costs.

Gas Demand

Demand for natural gas in California and the nation has increased in recent years. Gas use is up due to its competitive price and environmental attractiveness when compared to oil and coal. California gas use in 1993 was 1.9 trillion cubic feet (TCF). Although gas demand has been growing in recent years, current gas use is less than California's peak gas demand of 2.5 TCF in 1973. Rapid gas price increases during the mid 1970s to early 1980s coupled with falling oil prices and a recession in the early 1980s resulted in significant decreases in gas demand.

Natural gas currently provides about one-third of all energy consumed in California. Gas use is second only to oil, which is by far the dominant energy source at 52 percent of the total. As shown in Figure 5-2, California gas consumption is fairly evenly spread over most end-use categories, or "sectors."

Figure 5-2
1993 California Natural Gas Consumption by Sector



Gas Prices

Growing competition in the gas industry has caused gas prices to decline in recent years. The average United States wellhead gas price in 1994 was \$1.83 per thousand cubic feet (MCF). Wellhead prices peaked in 1984 at \$2.66 per MCF, about double the current price when corrected for inflation. Today's gas wellhead prices in real terms are about what they were when the federal government began to phase out wellhead price controls in 1978. Gas prices are also low compared to oil prices. The world price for crude oil in international trade in 1994 varied considerably, but was mostly within the range of \$13 to \$18 per barrel, which is equivalent on an energy basis to roughly \$2.15 to \$2.85 per MCF.

Unlike unregulated wellhead prices, the cost of transporting the gas from the wellhead to the consumer is regulated as a monopoly activity. Gas transportation in interstate commerce is regulated by the Federal Energy Regulatory Commission (FERC) while within California it is regulated by the California Public Utilities Commission (CPUC). Both regulatory commissions set rates based on the actual costs incurred to provide the transportation

service (although discounts are permitted under certain circumstances).

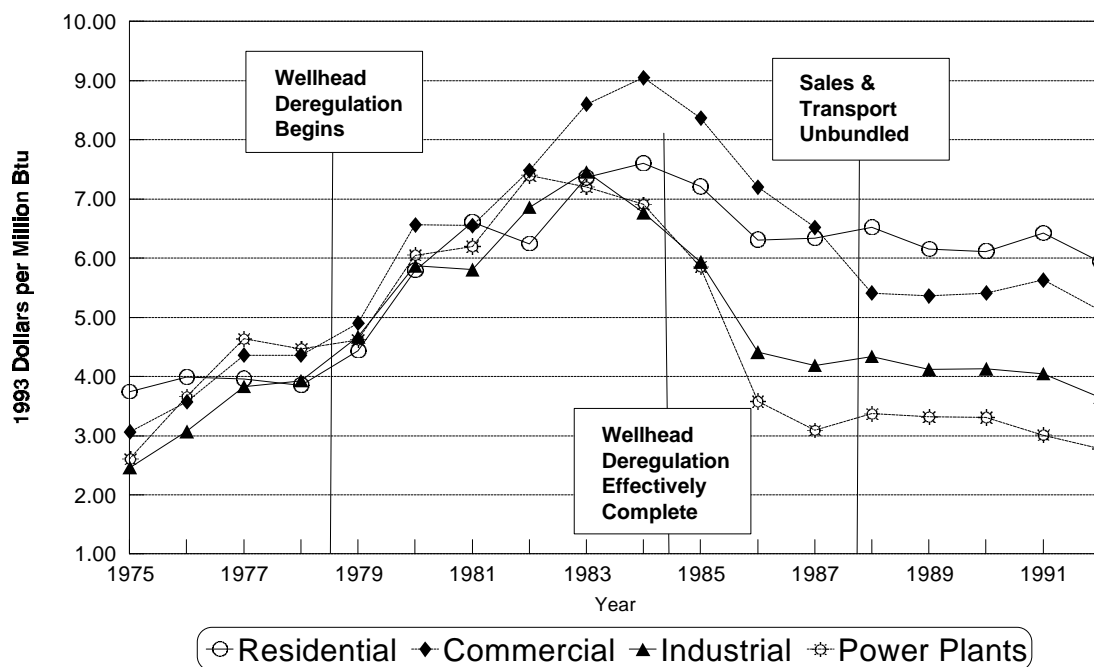
Figure 5-3 displays the price of gas to various sectors of California consumers since 1975. Prices used to be similar for all sectors. Prices diverged starting about the mid 1980s, when the CPUC moved to a cost-based rate structure. Residential rates are the highest because it costs more to serve small customers than large ones and because residential customers require the highest quality of service.

Residential and other small consumers of gas still receive traditional gas service from their local utility. Larger gas consumers (typically, industries and power generators) may purchase their own gas from producers or marketers and pay the utility to deliver it to their premises. Large consumers, however, may opt to buy gas from the utility and receive the same type of service as small customers.

Regulations

As discussed in the *1993 Fuels Report*, the major building blocks are largely in place for a restructured, market-based natural gas industry in

Figure 5-3
California Natural Gas Prices by Sector



California. These major pieces are: deregulated wellhead gas prices; separate availability and pricing of gas sales, transportation, and underground storage services; nondiscriminatory provision of gas pipeline transportation; and rates for regulated services designed to promote economic efficiency.

Despite widespread agreement on the broad regulatory structure defined by these major building blocks, gas regulations continue to evolve. Regulators are focusing on two complementary ideas: instituting competition in place of regulation where feasible, and assuring that, where regulation is necessary, the rates are market-sensitive to promote economic efficiency. The following sections describe some areas in which the gas industry is grappling with ways to further increase competition and economic efficiency.

Incentive Ratemaking

Some aspects of the gas industry cannot be deregulated because they retain monopoly characteristics. Long-distance transportation (at least in part) and local distribution of gas through pipelines fall into this category. Even though these services are regulated, regulators can introduce some market discipline into utility provision of the services through the use of incentive ratemaking.

"Incentive rates" are rates designed to give the utility a financial incentive for superior performance from the ratepayers' perspective. Under a typical incentive rate, if the utility can provide services at lower cost, the utility and the ratepayers share the savings and everyone is better off. Properly designed incentive rates will provide utilities with greater flexibility to find least-cost options, as well as reward utilities for innovation and use of improved technologies. Further, incentive ratemaking can impose a lower administrative and regulatory burden on all participants in the regulatory process. Both common sense and experience indicate that the "carrot" of incentive rates works better than the "stick" of traditional ratemaking.

A form of incentive ratemaking now being tried experimentally in California is called performance-based ratemaking, or PBR. Under PBR the size of a utility's profits depends on its performance. PBR incentives are balanced because both rewards (for superior performance) and penalties (for substandard performance) are possible. Performance

is measured in relation to a clear, objective benchmark that represents a reasonable approximation of the market environment faced by the utility. Of course, the point at which the benchmark is set is critical to the success of PBR.

PBR was applied first to the cost of gas purchased by gas utilities for resale to customers. Experimental PBR gas rates became effective for San Diego Gas and Electric Company (SDG&E) in August 1993 and Southern California Gas Company (SCG) in April 1994, and are expected soon for Pacific Gas and Electric Company (PG&E). PBR is being extended to include gas utilities' non-gas costs (so-called base rates). Experimental PBR base rates became effective for SDG&E in January 1995 and are being developed for SCG and PG&E. PBR rates for gas sales are being watched closely because of their potential to be applied to electricity sales as electricity regulatory restructuring proceeds in California.

On the national level, the FERC, which regulates interstate gas pipelines, is also experimenting with incentive ratemaking. The FERC has embraced the concept that, where discrete services it regulates are competitive, the rates should be market-based. In practice, the FERC sets a range within which rates are found to be reasonable and market competition is permitted to determine the price within that range. Where services are not sufficiently competitive to permit market-based rates, the FERC prefers incentive rates to traditional cost-of-service rates.

The FERC has already adopted market-based rates for some underground gas storage services and for gas inventory charges associated with gas sales by pipeline companies. The FERC is currently considering the extent to which incentive rates, now largely restricted to gas sales services, should be extended to gas transportation services. In some instances pipeline transportation services might be sufficiently competitive to permit market-based rates. The two most likely areas for market-based transportation rates are capacity release (discussed in the next section) and pipeline corridors between major market centers when several pipelines compete.

Capacity Release

The California gas utilities historically held the contractual rights for the use of all the firm

(dependable) capacity on interstate gas pipelines coming to California. As the utilities' monopoly over gas sales ended in the late 1980s, they no longer needed all of the interstate capacity. The need arose to rationalize the gas transportation system by shifting a large part of the pipeline capacity rights to other parties who were now buying their own gas and needed a means to ship it to California. This rationalization has been slow and difficult because the old arrangements were fixed in place by long-term contracts. The existing contracts expire in stages over the next dozen years.

Under existing regulations, the utilities can reduce (but not eliminate) the financial impacts on themselves and their rate payers due to these contracts without waiting for contract expiration. They can release the capacity back to the pipeline companies, which will remarket the capacity. Alternatively, the utilities may market the capacity themselves, if they follow prescribed nondiscriminatory procedures. By regulation the maximum price the utility can charge, called the "rate cap," is the FERC-approved rate that the utility currently pays the pipeline. If the utility receives less than the rate cap for released capacity, it must come up with the remainder, because it still has an obligation to the pipeline for the full contract price.

Experience with capacity release has been mixed. On the plus side, large amounts of capacity have been released and remarketed, making firm capacity available to parties that previously could not obtain it. With the creation of a market in firm capacity, competition has been unleashed. This competition has driven down the price of released capacity on some pipelines, thus reducing gas costs for some California consumers.

On the negative side, utilities are still stuck with some unwanted capacity, for which they must pay the pipeline company. In addition, for the capacity released to other buyers, they must pay the difference for released capacity that sold at less than the rate cap. (In both cases, the utility passes the bill along to ratepayers.) Moreover, the capacity release procedures specified by regulation have proved cumbersome and expensive, forcing transactions in economically suboptimum directions. The FERC has made some improvements and is considering further changes. For example, the FERC has requested comments on whether the price cap should be lifted to allow the market to allocate

capacity more efficiently. The market for released capacity may be sufficiently competitive to support unrestrained market-based rates.

Bypass of Utilities

Traditionally, utilities and pipeline companies have been partners in the gas industry. Pipelines purchased gas from producers, transported it to utilities, which then bought it for distribution and resale to consumers. As competition in the gas industry increased, it was natural, perhaps inevitable, that some degree of competition should creep into the partnership between utilities and pipelines. One form of competition appearing in numerous locations throughout the country is interstate pipelines bypassing the local utility and selling gas directly to consumers.

Now that two interstate pipelines enter California, rather than stopping at the state border as they all did prior to 1992, some large gas users in the state have the option of bypassing their utility. If the user is located close to one of the interstate pipelines, the pipeline might be able to offer a lower price than the tariffed rate charged by the utility. (Being regulated by the FERC, the pipelines are not bound by the rates that the CPUC sets for the utilities.)

If a gas customer bypasses the utility system, the utility foregoes the revenues it otherwise would have received. Under the current regulatory scheme, to achieve its authorized revenues the utility may need to raise its rates to remaining customers to cover fixed costs and make up the difference.

The utilities are battling to avoid bypass of their systems. The CPUC permits the utilities to negotiate special, discounted contracts with gas users who might otherwise bypass the utility. (Whether the rate payers or the utility shareholders must shoulder the cost of the discounts varies by utility.) The utilities also adopted major programs to cut costs and improve services in order to better compete with all their competitors, including pipelines and other energy types such as coal and electricity.

At the time of the *1993 Fuels Report*, the Mojave Pipeline Company was proposing to extend its interstate pipeline, from its present terminus near Bakersfield, northward to Sacramento and the San Francisco Bay Area. The extension would

considerably expand the opportunities for large gas consumers to bypass the utilities, principally PG&E.

The outcome of Mojave's proposal is still unclear as of this writing. Some of the proposed customers of the Mojave extension have withdrawn, hurting the outlook for the project. Nevertheless, the competition from Mojave's proposed extension has already affected the state because the utilities have reduced prices to potential bypass customers to retain their business.

The Los Angeles Department of Water and Power (LADWP), whose gas-fired power plants receive their fuel over the SCG system, is considering bypassing that utility. The current CPUC investigation to restructure the regulation of electricity in California is motivating electricity utilities, including LADWP, to look harder at ways to control costs. LADWP is considering building a pipeline from its power plants to connect to the Kern River/Mojave joint pipeline in Kern County, to avoid the gas utility's transportation charges.

THE FUTURE GAS MARKET

The Energy Commission's outlook for the natural gas market in California and the rest of North America is positive. Ample supplies of natural gas will be available with little or no curtailment, the price of natural gas will remain competitive with alternative energy sources (fuel oil, coal), and demand will continue to show strength for the next two decades. The environmental benefits of natural gas vis-a-vis alternative energy sources further supports the Energy Commission's basic conclusion.

Even with this optimism, the Energy Commission recognizes that the future direction of the natural gas market in California could vary considerably, depending on the direction of several energy markets, as described below.

- **Electricity Restructuring:** Since the CPUC issued its electricity "blue book" in April 1994 outlining a comprehensive restructuring of the electricity marketplace, energy market representatives, utilities, and regulators alike have invested considerable time developing a program that will eventually allow all customers an opportunity to select their suppliers of electric power and transmission service.¹ The resultant competition among electricity suppliers for

access to customers is expected to lead to greater efficiency and an increased emphasis on cutting costs. After electricity restructuring, most new power plants are likely to be gas-fueled because they produce the cheapest electricity of all power plant options. Some experts expect these new power plants to cause a large increase in the level of gas consumption for power generation.

On the other hand, countervailing forces could tend to reduce gas consumption. It is unclear how new and efficient power plants would affect the use of existing power plants. If the new plants are used to replace old, inefficient, gas-fired plants, the total amount of gas consumed might decrease, even as total electricity generation from gas-fired plants increase. In addition, as competition is leading to lower electricity prices, electricity might capture some end-use markets that are now served by gas. Another reason for reduced gas competition in California could be due to increased purchase of cheap power from out-of-state facilities, reducing the need to generate electric power within the state.

Whether total gas consumption would increase or decrease as a net result of all these countervailing forces is currently unknown. Therefore, staff looked at sensitivity cases that assumed either lower or higher gas consumption for electricity generation than was assumed in the Base Case. These sensitivities and their effect on forecasted gas prices are described later in this chapter.

Nonetheless, the Energy Commission believes that electricity restructuring will be good for the gas industry because market competition encourages more efficient market activity. Gas and electricity will increasingly compete with each other, as both markets increasingly converge into a single energy market. Further integration is expected during the next 15 years, as the efficiency of gas-fired generators is improved and the cost of producing electricity is reduced to as little as three cents per kilowatt hour.²

Electricity restructuring will increase the use, for both gas and electricity markets, of market hubs and computerized services that allow customer access to immediate information on energy prices and availability. Customers will be able to choose the best combination of energy types for

their needs, placing downward pressure on natural gas prices at the burner-tip. The downward pressure will reduce the likelihood of customers switching to alternate energy sources. The ultimate benefit, however, is contingent on how far regulators allow market competition to operate. The issue of electric restructuring will be fully addressed in the *1996 Electricity Report* that is underway at the Energy Commission.

- **Mexican Markets:** Mexican markets will also impact the direction of the natural gas market in North America during the next 20 years. The North American Free Trade Agreement certainly improves the likelihood that more gas produced in Mexico will penetrate markets in the United States and vice versa. Mexico has 187 TCF of potential reserves but does not have the infrastructure developed to bring much of that gas to the marketplace.³ Several signs indicate that change may be on the horizon. In April 1995, the Mexican congress approved opening storage, distribution, and transmission to foreign investors. The following month, Mexico's Energy Minister told Canadian regulatory officials and pipeline companies that his country intends to compete with Canada for market share in the United States.⁴

The improved ability of Mexican gas to travel to Northern Mexico and the United States ultimately depends on the actions of state-owned Petroleos Mexicanos (PEMEX), which holds all rights to exploration and production. According to the Canadian Energy Research Institute (CERI), 30 percent of the Mexican government's revenues come from PEMEX. CERI expects PEMEX to continue placing a high priority on developing supplies to the country's growing oil market. As a result, most natural gas development will continue to be associated, limiting growth in Mexican natural gas production capability.

From the perspective of United States and Canadian producers and transporters, the opening of storage, distribution, and transmission systems in Mexico to foreign investors clearly improves the outlook for increased deliveries of gas to Mexico. Four companies presently have pipelines exporting gas to Mexico, with a combined capacity of 950 MMCF/D.⁵ Other companies are presently targeting Baja California as the next place to build pipeline

capacity to deliver gas to Mexico. These pipelines are designed primarily to serve power plants and cities along the United States-Mexican border which are moving away from the use of high sulfur fuel oil due to severe pollution problems in the region. With distribution open to foreign investment, additional Mexican markets beyond the immediate international border may soon be open to United States and Canadian companies.

- **Alternative Fuel Markets:** The alternative fuel market will clearly impact the outlook for natural gas. In the late 1980s, methanol was touted as the alternate fuel of choice in the transportation sector. Now, natural gas is beginning to assume that role, not only in California but also in the rest of the United States. Clearly, the ability of natural gas vehicles (NGVs) to penetrate conventional and alternate fuel vehicle markets will affect the outlook for the natural gas market. Estimates of future NGV demand in the year 2010 have been as high as 1.2 TCF, made by organizations such as the Natural Gas Coalition, the Gas Research Institute, and the American Gas Association. Recognizing the optimistic nature of the estimate, the group contends a "realistic" estimate of 370 BCF in the same year.⁶ As part of the Energy Commission's work directed by Senate Bill 1214, the Energy Commission estimated that NGV sales in California will be about 3 percent of the total car or light-duty vehicle sales by the year 2010.⁷ These estimates are subject to considerable uncertainty, given the uncertainty surrounding whether the California Air Resources Board can successfully implement its low emission standards on new vehicle sales beginning in 1998.

Also within the alternative fuel market is the potential to displace natural gas as the so-called "fuel of choice" for stationary applications. The Energy Commission recognizes that other energy alternatives to traditional natural gas resources may become increasingly available during the forecast horizon, namely Liquefied Natural Gas (LNG) and synthetic fuels. LNG is already a viable energy source throughout the world, accounting for 3 TCF of natural gas consumed in 1993. Estimates suggest that worldwide LNG production, which comes primarily from Indonesia and Algeria, could increase more than two-fold by 2010.⁸ The potential for LNG to increase its small North American natural gas

market share ultimately depends on the amount of LNG regasification capacity in the region. Four plants along the eastern seaboard and the Gulf of Mexico presently can regasify 1,002 BCF per year.⁹ Each facility has sufficient space to expand capacity by an additional 50 percent. Due to the high cost of LNG versus pipeline gas, two of the plants are presently idle and the other two operate at much less than full capacity.

Synthetic natural gas produced through coal gasification and hydrogenation provide another alternative source of energy that could compete with the traditional natural gas supplies. Generally referred to as the "backstop" supply, synthetic fuels present an upper bound on natural gas prices because of the ability to produce it in effectively unlimited quantities at a certain price at some point in the future. The development of coal gasification still faces many technological challenges before becoming economically viable. As such, the Energy Commission does not expect these backstop alternatives to be commercially available for at least 15 years. Unforeseen market conditions could, however, accelerate the development during the 20-year planning horizon.

- **Interstate Pipeline Transportation:** A final point clouding the direction of the natural gas market is the industry's own gas transportation restructuring. On the positive side, pipelines and holders of firm interstate pipeline capacity (shippers) can release their capacity for use by other shippers through a capacity release program. This program has effectively created market-based ratemaking mechanisms to enhance market competition. Competition in this environment will be most effective as long as excess capacity is available. If, however, capacity is constrained and priced at the maximum rate, customers who would be willing to pay more than the full tariff rate may not be able to obtain the capacity.

FERC recently began a further investigation into market-based rates and several alternatives are being considered. For pipeline corridors where market competition is evident, FERC is leaning towards removing maximum tariffs from the competing pipelines. In regions with no competition, FERC has suggested the status quo. Hybrids combining both approaches have also been recommended. Whatever methodology is

ultimately selected, it may be several years before a new market-based rate program is adopted in the interstate marketplace.

For interstate pipelines serving California, interstate transport rates are effectively market-driven. With approximately 2 BCF/D of excess capacity available, third-party shippers can obtain significant discounts to use the capacity for terms of varying lengths through the capacity release process. Capacity has been discounted as much as 95 percent and has often been discounted more than 75 percent in any given month. As a result, natural gas prices delivered to California utilities have been among the lowest in the nation. With significant levels of excess capacity to California anticipated through at least 2002, California end-users should continue to benefit from transportation competition.

At the utility distribution level, the extent of market competition is several years behind facilities subject to FERC jurisdiction. Even so, customers in California can negotiate discounted intrastate transmission rates but presently cannot bid for any unutilized in-state pipeline capacity. The strongest case for discounted rates usually applies to a customer who can show to the CPUC an "imminent" ability to bypass the utility if the bypass pipeline can serve that customer for a lower rate. To date, the CPUC has approved more than two dozen such contracts.

In Decision 94-02-042, issued February 16, 1994, the CPUC stated its intent to investigate in-state transmission competition. This investigation will likely become the driving stimulus to place the level of competition inside California on par with that experienced at the federal level.

The single most important transportation issue jeopardizing the positive outlook for natural gas during the forecast period is stranded pipeline costs. During the next several years, several significant contractual commitments between interstate pipelines and firm capacity holders will expire, leaving unanswered who will pay for pipeline capacity stranded after the contract's end. During the forecast period, PG&E's commitments on El Paso and Pacific Gas Transmission pipelines will expire, as well as SCG's holdings on El Paso and Transwestern. The largest piece, PG&E's 1,140 MMCF/D

holdings on El Paso, will expire at the end of 1997. Depending on the direction of FERC in its market-based ratemaking investigation, end-use customers could pay considerably higher per unit transmission rates in the near future.

The remainder of this section provides the Energy Commission's Base Case assessment of the natural gas supply, demand, and price outlook for the next 20 years. Following the assessment are several sensitivities and scenarios considered in this analysis.

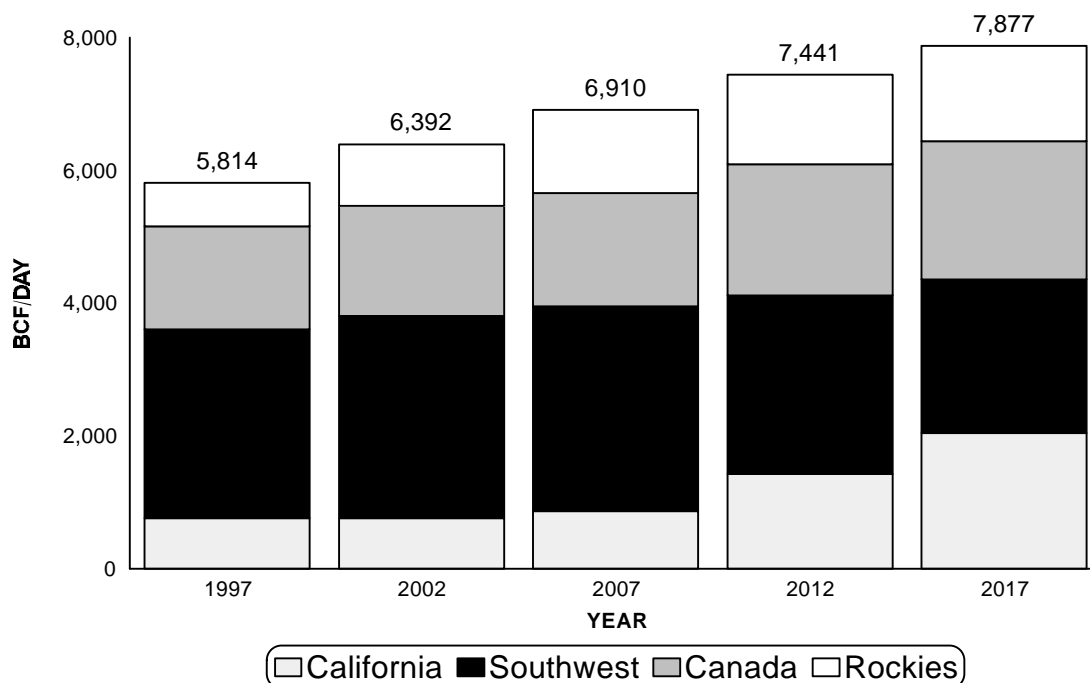
Natural Gas Supply Outlook

Natural gas supplies are expected to be abundant during the next several decades. The Energy Commission estimates a total resource base (gas recoverable with today's technology) for the Lower 48 of 1,056 TCF, enough to satisfy current production levels for the next 60 years. This estimate is conservative, given that a significant portion of Canada's 383 TCF of gas will serve Lower 48 gas markets as well. Furthermore, technological improvements in exploration and drilling activity should allow producers to access resources neither considered economically recoverable today nor part

of the resource estimate. The pace of these improvements has been accelerated by the transition from a highly-regulated to a market-competitive gas industry during the past 15 years.

The Energy Commission's latest resource assessment offers several insights about natural gas supplies. First, the Gulf Coast region will continue to dominate the Lower 48 gas market, producing more than 8 TCF per year throughout the forecast period. Anadarko and Permian production will continue to show strength while the Rocky Mountains will play a significant role in meeting requirements in the Western United States. Canadian production will rise from 4.4 TCF in the 1992 base year to nearly 6.7 TCF in 2017. Much of this increase is fueled by exports to the United States, which is expected to surpass 3.2 TCF by the end of the forecast period. With respect to supplies available to California, Southwest gas will slowly relinquish its role as the dominant gas supplier to the state by 2017 (Figure 5-4). In the 1992 base year, Southwest suppliers held a 58 percent share of the market. With increased access to Canada and the Rocky Mountains due to the completion of the Pacific Gas Transmission (PGT) expansion and the Kern River pipeline, the Energy Commission

Figure 5-4
California Supply by Source



estimates the Southwest share to fall to 29 percent by 2017. Most of the remaining strength in Southwest market share occurs in the San Juan Basin. Driven mostly by coalbed methane production, San Juan market share increases to 43 percent in 2002 but drops to 27 percent by the end of the forecast period. Permian supplies to the state shrink to virtually zero as its share of the California market declines from 18 percent in 1992 to 2 percent by 2017.

Canadian supplies gain and retain one-quarter of the California market through the 20-year forecast period. Rocky Mountain shippers double their market share by 2017. California producers, while experiencing a decline in market share towards the end of the decade and the early part of the next decade, will realize significant market share gains thereafter. This gain will occur as long as California producers can take advantage of improvements in drilling technologies that lower drilling costs and increase success ratios in the future. The Energy Commission will further investigate this issue in the development of the *1997 Fuels Report*.

Natural Gas Demand Outlook

The Energy Commission anticipates natural gas demand in the Lower 48 to reach 26 TCF by 2017, a 1.4 percent annual increase during the next 20 years.

The projection is higher than that presented in the *1993 Fuels Report*, which estimated a 1.1 percent increase. The higher demand estimates can be attributed to: 1) market competition, as described in the previous section; 2) changes in public policy designed for environmental protection, and 3) the emergence of new gas technologies in end-use sectors (e.g., more cost-effective appliances).

Within California, total natural gas demand is forecasted to grow 1.1 percent per year during the forecast period for all sectors (Table 5-1). The largest increase on a percentage basis is forecast to occur in the power generation (UEG and cogeneration) market, whose demand grows at a combined 1.9 percent per year. In absolute numbers, this increase amounts to more than 1 BCF per day of additional demand by 2015. Since environmental regulations severely limit the use of petroleum and coal in the state for stationary sources, natural gas has become the clear fuel of choice within the power generation sector. In other states with less stringent environmental restrictions and abundant resources of coal, natural gas demand is not necessarily the fuel of choice. As a result, demand growth for natural gas by electric generators outside California is less certain. As discussed in the previous section, however, demand for natural gas in the electricity generation sector will be influenced due to the electricity restructuring program

Table 5-1 NATURAL GAS DEMAND IN CALIFORNIA (MMCF/D)				
	1992	2002	2015	Pct Annual Growth Rate
Residential	1,332	1,453	1,609	0.8
Commercial	634	625	721	0.6
Industrial	1,130	1,077	1,170	0.2
Natural Gas Vehicles	0	78	136	N/A
Enhanced Oil Recovery	724	858	843	0.7
Utility Electric Generation (UEG)	1,535	1,307	2,221	1.6
Cogeneration	451	765	847	2.8
Total	5,806	6,164	7,549	1.1
Note: Annual growth rates are computed from 1992 to 2015.				

underway in the state. Sensitivity analyses in the following section address these concerns further.

Residential and commercial demand for natural gas is expected to show only modest growth during the forecast period, increasing less than 1 percent per annum. This is due to increased energy conservation, technological advancements producing more efficient appliances, and demand-side management activities.

Besides the "traditional" demand sectors, the Energy Commission anticipates the development of a substantial natural gas vehicle (NGV) market. Demand for natural gas in the NGV market is expected to grow from 12 MMCF/D in 1997 to 136 MMCF/D by 2015, representing 1.8 percent of the total natural gas consumed (in 2015) in the state. Although not indicated in Table 5-1, the Energy Commission anticipates a 14 percent annual increase in NGV demand from 1997-2015, considerably lower than the 21 percent annual increase projected in the *1993 Fuels Report*. The reduction is a result of independent analysis recently performed by the Energy Commission's Demand Analysis Office staff.¹⁰

Natural Gas Price Outlook

The Energy Commission forecasts natural gas prices both at the point of production (wellhead) and the point of consumption (burner-tip). Since 1989, the basis for all Energy Commission-sanctioned natural gas price forecasts has been the North American Regional Gas model, which computes a generalized equilibrium solution for supply, demand, and price in each region throughout North America. Energy Commission staff develop the input data and assumptions in cooperation with all segments of the gas industry in an open, public process. For more information on the model and methodology, see the *1995 Natural Gas Market Outlook*.

Natural gas wellhead prices for the Lower 48 are expected to grow at an annual rate of 3.6 percent on a real basis over the 20-year forecast period, from \$1.62 per thousand cubic feet (MCF) in 1997 to \$3.28 per MCF in 2017 (expressed in constant 1993 dollars). The forecast is considerably lower than those prepared for previous fuels reports (Figure 5-5), primarily due to the Energy Commission's latest resource analysis reflecting

lower capital costs and a slightly higher potential resource estimate.

Comparing specific producing regions except the Northern Great Plains, the Energy Commission expects the Rocky Mountains to become the least-expensive Lower 48 natural gas supply region at the wellhead after 1997. Alberta producers will provide the most attractive wellhead prices in Canada after 2002, with prices in British Columbia and Alberta virtually identical during the next seven years.

The relationship between wellhead prices in Alberta and the Rocky Mountains bears special attention. Historically, Alberta wellhead prices have been as much as \$0.50 per MCF lower than Rocky Mountain and other supply regions in the Lower 48. The Energy Commission's analysis suggests this price relationship will change by 2012. The shift occurs because Alberta's resource will be depleted more rapidly than the Rocky Mountains and therefore become more expensive to produce in later years.

End-Use Price Outlook

Most consumers will continue to experience increases in natural gas prices during the next 20 years. The Energy Commission projects that industrial gas prices (in 1993 dollars) will increase 1.4 to 2.6 percent annually between 1997 and 2015, depending on the utility service territory. Prices for natural gas consumed in the electric generation sector during that same period are expected to rise 2.1 to 2.7 percent per year, although prices will remain relatively constant for the next 5 to 10 years. Residential customers will experience rate changes ranging from a 0.1 percent decrease to a 1.2 percent increase on an annual basis, depending on the utility service area.

Figure 5-6 presents the utility electric generation forecasts for the three major utilities in California. Gas prices presented in this report are considerably lower than the *1993 Fuels Report* forecast. Three factors account for the decline. First, the Energy Commission's updated resource assessment reflects lower capital cost per unit of resource available, hence lowering wellhead price projections. Second, interstate pipeline transportation rates are lower, reflecting the impact of capacity release programs which allow customers to transport gas on the

Figure 5-5
U.S. Lower 48 Natural Gas Wellhead Prices

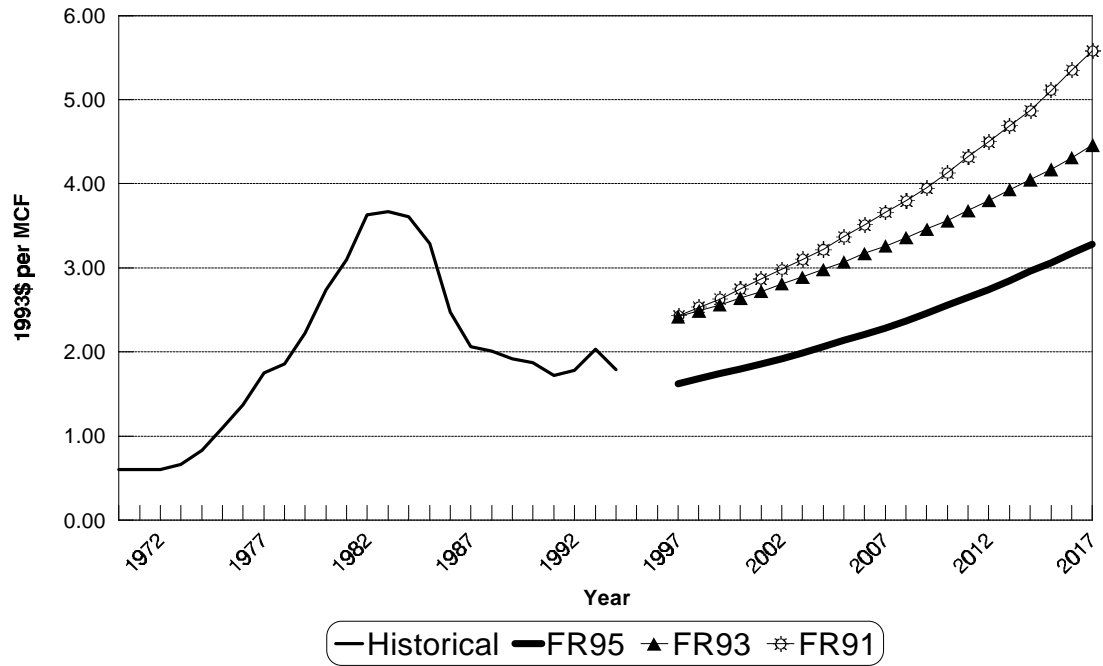
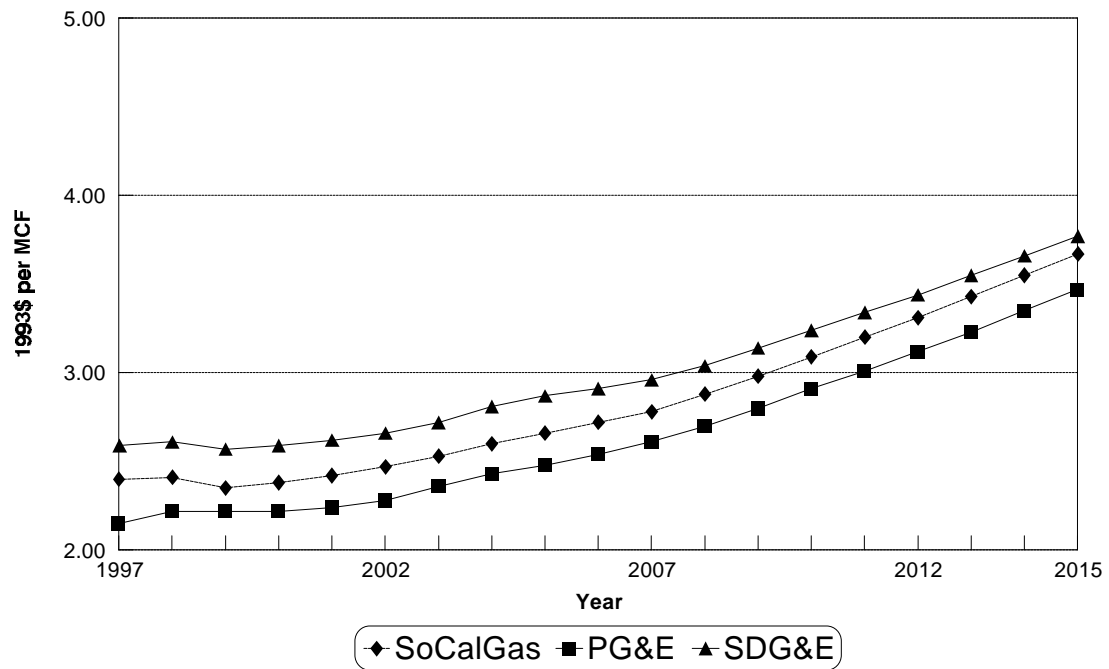


Figure 5-6
Regional UEG Natural Gas Prices



interstate pipeline system often at significant discounts. Finally, since competition has forced natural gas utilities to reduce their operating costs, intrastate transmission and distribution cost projections are lower. The combined effect of these changes produce lower price projections at the burner-tip.

Sensitivities

Given the uncertainty associated with the assumptions used in the Base Case, the Energy Commission prepared a series of sensitivity cases which test the impact of changing a single parameter on the natural gas price forecast. Several cases were reviewed, including changes in resource potential, backstop prices, discount rates, demand, and technological assumptions. The *1995 Natural Gas Outlook* details the sensitivity cases considered. A brief summary of the analysis follows.

Perhaps the greatest sensitivity on natural gas prices was on assumptions regarding the owner and producer's discount rates. The owner's discount rate is defined as the "rate used by the original owner of a resource deposit to discount cash flows resulting from the sale of leases to resource producers." The producer's discount rate is simply the required rate of return on equity for all investments. The Energy Commission staff equated both rates at 6 percent (real) in the Base Case. In general, lower owner discount rates produced higher prices throughout the forecast horizon with the greatest percentage impacting near-term price estimates.

Assumptions about the resource base and backstop price also produced significant changes to Base Case price projections. In the Low Resource sensitivity, Lower 48 wellhead prices increased 17 percent to 20 percent, while the High Resource sensitivity decreased prices 3 percent to 5 percent. The forecast was also sensitive to the backstop price. The Energy Commission determined that every \$0.25 per MCF drop in the backstop price from the Base Case assumption of \$5.00 per MCF reduces Base Case wellhead prices by \$0.03-0.05 per MCF.

The market sensitivities tested by the Energy Commission did not produce a major impact on average prices and supplies for the Lower 48 and Canada in aggregate. Regional differences, however, told another story. Perhaps the most

important sensitivity was the impact on natural gas flows to California if the transportation costs of the PGT expansion were rolled into the PGT rate base. Two options are under consideration at FERC: 1) "rolled in" which spreads out the capital cost of the expansion over all users of the system and 2) "incremental" which applies all capital costs to the users of the new facility components. The Energy Commission determined that natural gas flows to Southern California would increase with rolled in rates, but decrease slightly to Northern California.

Applying different assumptions about demand projections in sensitivity cases produced little impact with respect to demand assumptions in the Lower 48, California, and Mexico.

Scenarios

As in past fuels reports, the Energy Commission performed a scenario analysis to understand possible outcomes of natural gas supply and price trends under different "plausible" future circumstances. Scenarios produce a framework whereby future supply, demand, and price uncertainties can be investigated. Projections resulting from this analysis present a range of natural gas prices that can be expected due to changing market conditions.

Staff constructed two scenarios in addition to the Base Case price forecast. The Base Case assumes "business as usual," with a continuation of the present trends for all key gas price determinants consistent with the *1993 Fuels Report*. The Competitive America and Natural Gas Dominance scenarios take broader energy market views. For each scenario, staff developed a set of assumptions for key determinants that impact future availability and price of natural gas in the United States and California. The assumptions were then used in the model to provide a set of gas price and supply projections.

The Competitive America scenario assumes robust economic growth, with market competition the driving factor. Environmental problems are remedied by the market with reduced oversight by regulatory agencies. Rapid technological development is assumed to occur, which increases the resource base and decreases the costs associated with bringing the resources to market. Jobs are created as environmental goals are met, and cleaner burning residual fuels and coal emerge as viable

alternatives to natural gas. Fuel competition is strong, and natural gas eventually loses significant market share to other fuels.

In Competitive America, oil and coal emerge as viable competitors to natural gas. As a result, natural gas consumption in the Lower 48 declines to 20.3 TCF by 2017, 22 percent below the Base Case. Wellhead prices increase only 2.5 percent per year through the 1997-2017 forecast period. California citygate prices increase at a modest 2 percent per year.

The Natural Gas Dominance scenario assumes increased natural gas usage due to efforts to reduce emissions from stationary and mobile energy sources. Specific regulations forbidding both oil and coal use force increased natural gas use in electricity markets. Furthermore, the nation as a whole continues its push away from nuclear power, resulting in the phase-out of nuclear power in the United States as licenses expire in the various nuclear power plants. Natural gas and electric vehicles penetrate the transportation market, with demand increasing substantively. With more stringent rules in place due to policies outlined in the federal Clean Air Act, costs associated with

developing and producing natural gas increase.

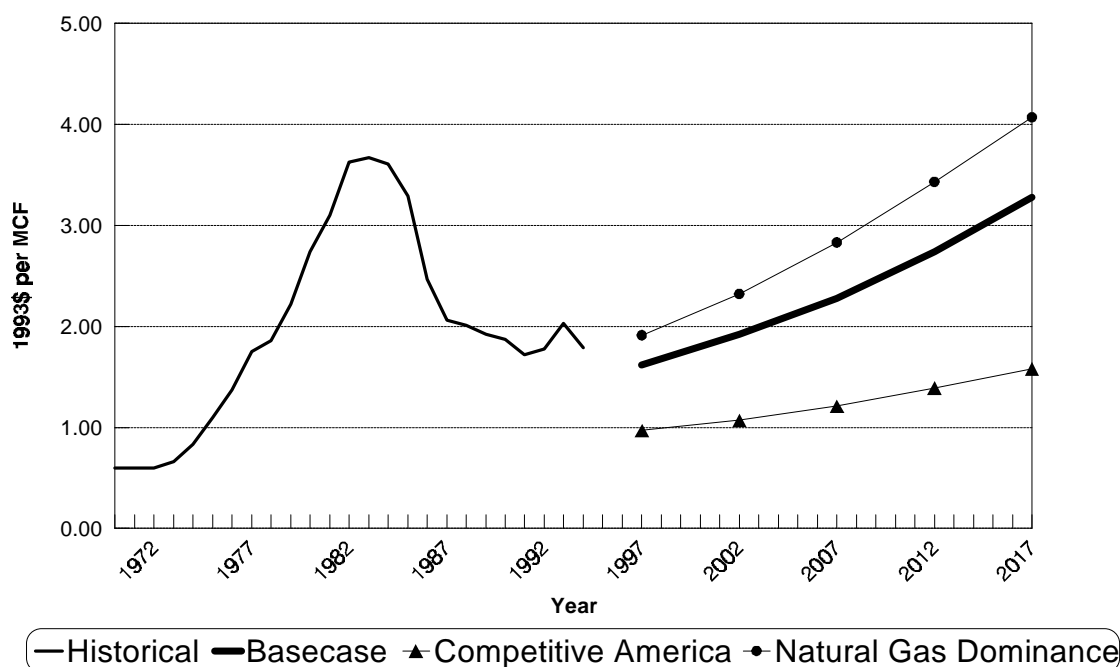
To meet the increased demand in the above scenario, natural gas production grows to 27.5 TCF by the end of the forecast period, 5.9 percent above the Base Case. Lower 48 wellhead and California border prices escalate at 3.9 percent and 4.1 percent per year, respectively.

Figure 5-7 compares the Lower 48 wellhead prices in the Base Case forecast with the two scenarios just described. Compared to the Base Case, the Competitive America case is \$0.65 per MCF lower in 1997 and \$1.70 per MCF lower in 2017. Wellhead prices in the Natural Gas Dominance case are \$0.29 per MCF higher in 1997 and \$0.79 per MCF higher in 2017.

The two scenarios demonstrate the impacts of uncertainty in key determinants of future natural gas prices. They do not, however, represent a projection of gas prices but indicate the outer limits of the excursion of prices above or below the Base Case forecast. The Energy Commission believes these extreme forecasts are not sustainable, considering that market forces would tend to counter balance the

Figure 5-7

U.S. Lower 48 Natural Gas Wellhead Prices Scenario Comparison



effects that either lower or raise gas prices. However, its use is recommended in electricity resource planning proceedings for analyzing the impacts of natural gas price forecast uncertainty.

INTEGRATED RESOURCE PLANNING

The main objective of a gas integrated resource planning (IRP) process is to achieve the lowest total cost of service by considering all supply and demand side options. The Energy Policy Act of 1992 (EPACT) directed states to consider the use of IRP for natural gas local distribution companies/utilities. The CPUC began a proceeding in 1993 to consider compliance with EPACT.

Since the late 1970s, the natural gas market has been undergoing significant restructuring and deregulation resulting in a more competitive market with lower gas prices. The current natural gas market is more competitive today due to the following: utilities are no longer the sole provider of gas; utilities' sales and transportation functions have been separated; utilities sell gas only to core customers (those that have not aggregated to purchase their own supplies); and expansions of interstate pipelines to California increased competition for gas supplies, thereby reducing gas costs in the state.

Because of deregulation and the level of competition existing in the gas market, utilities in California already perform informal IRP processes to enhance market share and corporate viability. The process begins with forecasting demand, including analyzing economic sensitivities and scenarios for a range of possible futures. Resource options, which exist as supply and demand side management (DSM) options, are then assessed. All potential resource options compete for demand in various econometric models to determine the optimal resource mix.

Two issues exist in using the IRP process for gas. First is the issue of whether or not gas DSM should be considered as a factor in the demand forecast or as a resource option with a derived, associated cost. In the natural gas price and supply forecast presented in this report, gas DSM is included as a reduction in the demand forecast. Gas DSM for this purpose incorporates existing building and appliance

standards, government programs, and utility programs. Estimating the extent to which pipeline demand or capacity-related costs can be avoided by future DSM is a difficulty experienced by utilities implementing IRP.

Second, there is a dispute about whether IRP should be employed from a utility/ratepayer perspective or a societal, public perspective. The latter may involve longer time horizons, smaller discounting of the future, and inclusion of environmental externalities.

Several benefit/cost (B/C) tests exist to measure and evaluate DSM programs. The following B/C tests are presently utilized: participant, societal total resource cost, utility, total resource cost, and ratepayer impact measure test. The specific economic variables included depend upon each test's intended use and which of the stakeholders' perspectives it represents. For example, the societal total resource cost test examines environmental concerns and societal costs and benefits of DSM programs.

Critics of gas IRP claim the potential benefits are inherently less than those from an electricity IRP process. They contend that supply-side decisions for gas utilities do not imply the large, long-term, irreversible cost commitments experienced in electricity and that the costs avoided by implementing DSM are less for the gas industry than electric.¹¹

Proponents believe there are many benefits from gas IRP which provide: information critical to supply portfolio planning, support for environmental objectives, information essential to determining system reliability and capacity needs, a methodology to assess risk associated with supply decisions and system investments, and a process useful in evaluating and establishing energy policy. A key component of gas IRP is DSM of natural gas supplies, the subject of the next section.

DEMAND SIDE MANAGEMENT

DSM has been aggressively pursued to meet California's growing energy needs while minimizing unnecessary growth in energy delivery infrastructure. Cost-effective energy conservation is less expensive and cleaner environmentally than building and operating new power plants or supplying and burning natural gas. Energy

conservation is the result of many public and private programs and individual choices. Fundamental restructuring in the natural gas industry has significantly affected both industry purchase decisions and natural gas DSM. In the 1980s, CPUC and FERC were restructuring the natural gas industry to increase competition and thereby reduce customer costs. The major changes were the separation of customers into "core" and "noncore" categories and the unbundling of transportation rates. These changes reduced the acquisition costs of gas and resulted in some DSM programs creating more revenue losses than cost reductions, reducing utility interest in DSM. However, DSM continues to evolve as a strategy in California's energy future.

Natural Gas Savings

The cumulative natural gas savings from all utility programs, building and appliance standards, public agency programs, and naturally occurring conservation during 1992 was 3.8 billion therms.¹² This cumulative impact includes remaining effects in 1992 of program expenditures in prior years.

From natural gas investor owned utilities' (IOUs) programs in 1994, 35.8 million therms of natural gas were saved through conservation and energy efficiency DSM efforts, less than 1 percent of California's total natural gas demand. By 2010, PG&E is projected to save 4 percent and SCG 2 percent of their respective core demand.¹³

Factors Influencing Natural Gas DSM

In 1995, the reasons for continuing DSM programs are changing. The energy market nationally, and in California especially, is undergoing considerable changes that influence prospects for natural gas DSM in the future. Among the influencing factors are air quality considerations, performance-based rate-making, legislation for social program surcharges, and electric industry restructuring. California's IOUs, and municipal utilities as well, are responding to the changes in today's energy market by proposing to reduce budgets allocated to DSM programs, revising the goals of these programs, and reevaluating the methods used to determine cost-effectiveness of their programs. Collectively, California IOUs spent 92 million dollars in 1994 on natural gas DSM programs and

have budgeted 104 million for 1995.¹⁴ Although this is a slight increase, the 1995 budgets are down 20 percent from the 1993 actual budgets totaling \$129 million.

Industry Restructuring

IOUs are attempting to reduce their rates in anticipation of increased competition in a restructured environment. Reducing DSM program spending through changes in funding sources, rate designs, and program designs help to keep rates low. Ultimately, getting the funding for DSM programs out of rates and into a non-bypassable distribution charge that would be collected from all energy users, not just IOU customers, appears to be a main utility goal as suggested by utility support of related legislation. Options for spending DSM money collected in this fashion range from continued utility programs to a statewide consortium or agency.

Through 1994, DSM programs have been paid for by the customers through their rates. The CPUC approves the IOUs' DSM programs and budgets and allows approved costs to be paid back in the rates. Since DSM reduces utilities' revenues by reducing consumption, the CPUC allows IOU shareholders to get earnings from successful DSM programs as an incentive for them to pursue energy conservation.

Performance Based Ratemaking (PBR)

As an alternative to traditional rate design, the IOUs are exploring PBR. The implications of PBR on DSM could be large and negative but are speculative at this point. At least one utility proposes to redesign its DSM program in response to anticipated competition whether or not PBR is approved. Some issues being considered by the utilities in their respective PBR/ DSM proposals include: rate design impacts on utility and customer incentives to conserve, what the redesigned programs will include, how low-income programs will fare, and the impact on the shareholder incentive mechanism and reporting requirements. The objective will be to maintain the incentive both for the customers to participate and for the utilities to provide energy conservation and efficiency measures.

Air Quality Interaction

The benefits of improved air quality due to conservation continue to be investigated and pursued. One IOU reports reductions of 3.4 million tons of CO₂, 1,379 tons of SO_x, and 5,063 tons of NO_x from its 1994 conservation and energy efficiency programs' electric and natural gas savings.¹⁵ Air quality agencies and districts continue to explore incentives for smaller customers to implement natural gas conservation technologies that will result in emission reductions.

In 1993, the South Coast Air Quality Management District (SCAQMD) adopted the Regional Clean Air Incentives Market (RECLAIM) which allows SO_x and NO_x generating facilities to buy and sell emissions credits. RECLAIM inherently has a financial incentive for end users to conserve and use energy more efficiently. In addition to RECLAIM, SCAQMD has designed measures intended to provide conservation incentives to a variety of sources too small to be included in RECLAIM in the residential, commercial, and industrial sectors. The specific measures targeting natural gas DSM proposed in the 1994 Air Quality Management Plan are: Area Source Credit Program for Commercial and Residential Combustion Equipment; Efficiency/Energy Conservation - Area Source Credits measure; and Clean Stationary Fuels, a fuel substitution measure.¹⁶

Fuel Substitution and Load Building

Fuel substitution measures such as replacing electric space heating with natural gas furnaces are programs which promote the customer's choice of natural gas rather than another energy source. The SCAQMD measure, Clean Stationary Fuels, is intended to phase-out use of fuel oil and solid fossil fuels from stationary combustion sources to achieve emission reductions. The CPUC uses another definition for fuel substitution. It only applies to programs that result in an end user switching from one utility fuel to another.

Mobile source emissions reduction efforts such as the utilities' low emission vehicle programs are included in some utility DSM programs because the purpose is to influence consumer demand for energy. According to the CPUC definition, the fuel

switching that occurs in the transportation sector from gasoline to alternative fuels such as compressed natural gas (CNG) and electricity would qualify as a load building program rather than fuel substitution since gasoline is not a utility fuel. Alternative transportation vehicles and fuels such as CNG are being developed and commercialized to achieve emission reductions and to some extent for energy security reasons.

Natural Gas DSM Goals

To better understand and evaluate the potential for future natural gas savings from DSM, the Energy Commission is building a projection methodology that will be available for demand forecasting efforts in the next *Fuels Report* cycle. In addition to this forecasting effort, the Energy Commission is participating in California Conservation Inventory Group and California Demand-Side Management Measurement Advisory Committee work to develop and implement contracts to further the state's knowledge of DSM results to date and future potential.

In May 1995, the Energy Commission began a collaborative effort called Energy Efficiency Services Working Groups. The goal for this group is to make a tangible contribution to enhancing opportunities for consumer choice of DSM and other unbundled energy services compatible with electric industry restructuring and societal economic efficiency. Through this process, the Energy Commission hopes to develop the best policies for publicly funded programs and to encourage private businesses to deliver energy efficiency services so that consumers have meaningful choices and are in a position to exercise that choice. The program goals and possibilities for publicly-funded DSM will also impact natural gas DSM roles utilities are expected to play in the future.

FORECAST OF COAL PRICES

California's primary interest in coal is for production of electricity in other states which is transmitted to California to meet part of our total energy demand. The price of coal affects both the generation of electricity at power plants owned by California utilities and the cost to produce coal-fired electric generation which is surplus to the regional needs.

This surplus energy from base load coal generation plants is made available to California utilities. The forecast of price and availability for such surplus energy has an impact on future electric generation capacity addition decisions for California utilities.

As in the last several Fuels Reports, coal prices are forecast for specific electric generation plants in the western states. Compared to previous forecasts, the current forecast of coal prices (in 1993\$) are slightly lower. This forecast is available in a report entitled ***Delivered Coal Price Forecast: 1995-2015*** .

There are a number of factors that may cause a change in the future price of coal for Mohave and Four Corners. At Mohave, these factors include: 1) uncertain costs for slurry pipeline refurbishment to extend its operation beyond its design lifetime of 2005, 2) proposals by the Secretary of Interior and the Hopi Tribe for Mohave to fund a water pipeline from Lake Powell to replace the water source for the slurry pipeline, and 3) the potential for increased coal royalties paid by Mohave when the reopeners are exercised in 1997. Four Corners may be affected by: 1) the expiration of Navajo tax waivers on the Four Corners plant and on the Navajo Mine which supplies coal to the Four Corners plant, and 2) who will be responsible for paying mine closing and retiree health costs incurred after mine closing.

The forecast assumed that the above factors would be more than offset by the effects of increased competition resulting from the restructuring of the electric energy industry as well as continued improvements in productivity at the subject coal mines. It is possible that these effects may be stronger or weaker than the forecast has assumed. It is conceivable that the effect of the factors listed above, and other unforeseen factors, could result in coal prices that are significantly higher or moderately lower than those provided in the forecast.

ENDNOTES

1. CPUC Dockets R.94-04-031 and I.94-04-032.
2. Dar, Vinod K. "The Electric and Gas Industries are Converging: What Does it Mean?," Public Utilities Fortnightly, April 1, 1995, p. 22.
3. Canadian Energy Research Institute (CERI), ***Towards a Continental Gas Market: The***

Integration of Mexico: Final Report to Steering Committee , March 1995.

4. Natural Gas Intelligence, "Waiting for the Regulatory Dust to Settle in Mexico," and "A Canada-Mexico Rivalry Taking Shape," Volume 14, Number 35, May 15, 1995, p. 8.
5. CERI, *op. cit.*
6. Natural Gas Week, "Gas Groups Design Battle Plan for Fast-Tracking NGV Growth," Volume 11, Number 19, May 8, 1995, p. 9.
7. California Energy Commission, ***1993-94 California Transportation Energy Analysis Report (Draft)*** , P-300-94-002, Docket 92-TFER-1, p. 52.
8. Enron Corporation. ***The 1995 Enron Outlook*** , p. 23.
9. Testimony of Ian Moncrieff, "The Future of the LNG Market," 1995 Fuels Report Hearing, May 11, 1995, p. 10.
10. California Energy Commission, ***1993-94 California Transportation Energy Analysis Report (Draft)*** , P-300-94-002, Docket 92-TFER-1, p. 52.
11. NARUC, ***Primer on Gas Integrated Resource Planning*** , December 1993.
12. California Energy Commission, ***1994 Energy Efficiency Report (Draft)*** .
13. California Gas and Electric Utilities, ***1994 California Gas Report*** and Workpapers.
14. PG&E, SCG, and SDG&E's ***Annual DSM Summary Reports*** , April 1995.
15. PG&E ***Annual Summary of DSM Programs*** , April 1995.
16. South Coast Air Quality Management District, ***1994 Draft Air Quality Management Plan, Appendix IV-A: Stationary Source Control Measures*** , April 1994.